Offshore wind sector deal

Transmission review
Short-term solutions

November 2019

Offshore Wind Industry Council

Context

It is a time of rapid change in the energy sector. In 2019, the offshore wind industry also welcomed the Sector Deal for Offshore Wind, which will deliver 30GW of installed capacity by 2030, which could meet a third of UK electricity demand.

At the same time, the power sector at large continues work to decarbonise against the back-drop of newly introduced net-zero legislation. Heading towards the long-term, in its recommendation to the UK Government, the Committee on Climate Change sees the delivery of at least 75GW of offshore wind by 2050, which will meet half of the UK's electricity demand.[1]

To deliver this ambition, the offshore wind industry has been lowering the cost of delivering projects whilst evolving projects to increase the value to consumers. This has delivered some outstanding results in the most recent auction round for Contracts for Difference, with offshore wind projects being awarded a strike price as low as £39.65/MWh, 30% lower than results achieved in the last auction only two years ago.[2] We believe it is also therefore appropriate to also evolve the way offshore transmission is also delivered as part of this evolution.

This paper focuses on short-term solutions that can be delivered within Tender Round 7-8 to produce practical measures that evolve the current regime in a pragmatic manner towards 2030. Additional to this paper is a series of complementary documents that also discuss longer-term changes towards 2050 that the offshore wind industry believes is necessary to ensure a fit-for-purpose framework to develop, build and operate offshore wind assets.

The timing is right for a review of the OFTO regime

The Sector Deal for Offshore Wind includes a commitment to perform an offshore transmission review to ensure a fit for purpose framework going towards 2030. This is an ideal opportunity for a review as the industry works to deliver offshore wind projects into the 2020s that reflects the maturing state of the industry that will have commissioned 10.4GW of offshore wind projects by 2020.[3]

Delivery of the additional 20GW in the 2020s to meet the Sector Deal target should be underpinned by not only the CfD mechanism to secure investment in projects at best value, but an offshore transmission framework that adequately reflects the evolving nature of offshore wind projects and trends that we see in the immediate future. Pragmatic questions within this paper seek to address the following:

- With increasingly larger and complex transactions (see Figure 1), how can the current processes be optimised to improve allocation of risk and ensure a more efficient divestment process?
- How can offshore transmission's regulatory framework better support innovation and optimisation?
- How can overall asset health be improved, and how does the framework account for the later life of projects?

The UK has just legislated for net-zero by 2050, and CCC has signposted that at least 75GW of buildout will be needed to achieve this. Setting the momentum for this delivery requires an examination of how offshore transmission is currently assessed and treated when connecting to the grid.

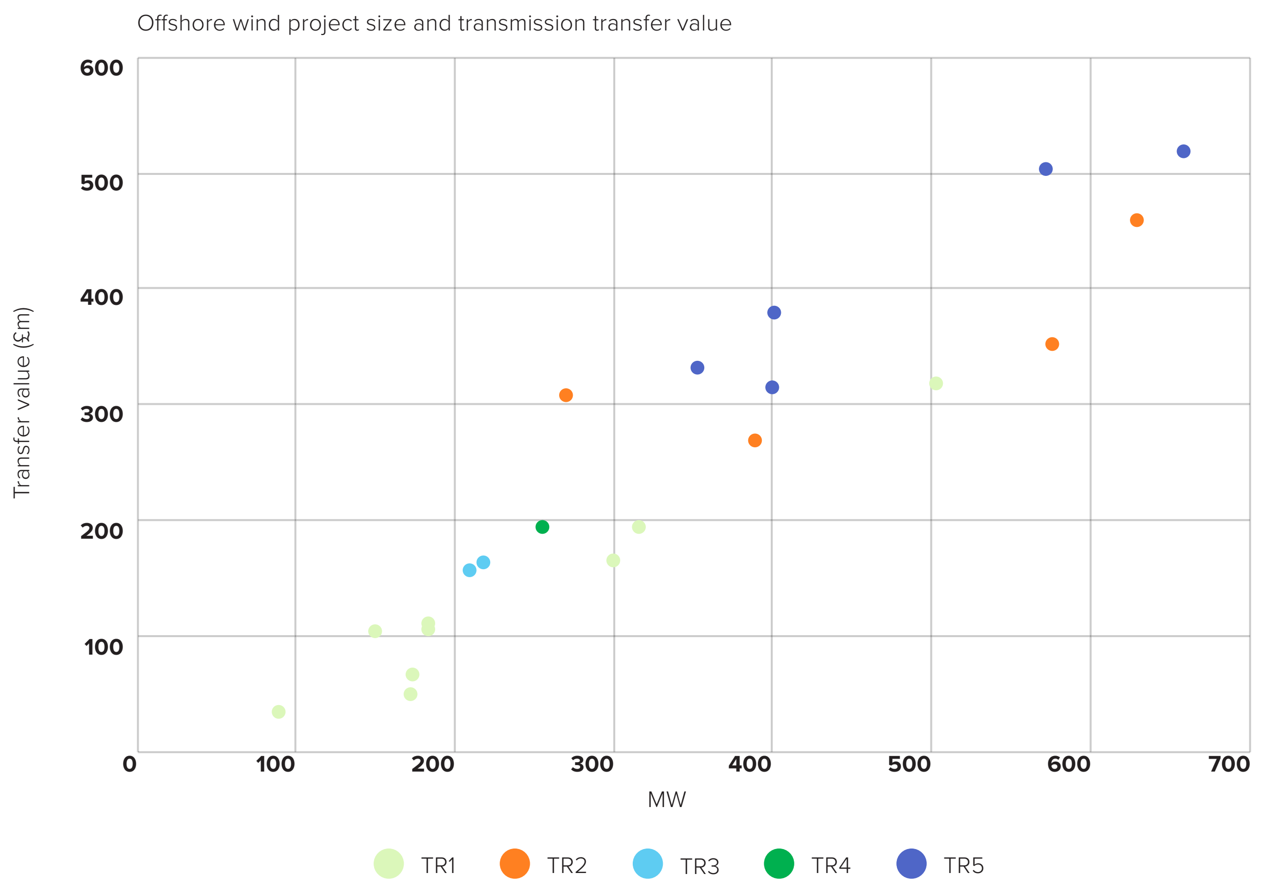
There is broad scope to change the current OFTO regime to meet challenges in the short-term

The current OFTO framework was first introduced in 2009 to attract new investors and induce cost reduction in what was then a frontier industry with no project-specific competitive tension under the Renewables Obligation. In the ensuing decade, competitive pressures via the CfD now provides the primary vehicle to offer the cost reductions that benefit consumers whilst delivering fit for purpose assets.

As the industry has matured, the rigidity of current OFTO arrangements have come to represent a barrier to optimisation and innovation as well presenting an unbalanced apportioning of risks between generators and OFTOs. These imbalances can range from basic, but critical optimisation areas such as dividing responsibility relating to safety equipment on offshore substations, through to more substantive innovations that will deliver better system integration or more efficient deployment of next generation transmission assets.

1. Committee on Climate Change 2019 – Net Zero: The UK's contribution to stopping global warming
2. CfD AR3 results announced 20 September 2019
3. As per WindEurope Outlook to 2022 dataset

Figure 1: Offshore wind project size and offshore transmission transfer value between tender rounds (Source: Ofgem)



These optimisations and innovations will allow for better system integration for high volumes of renewable energy.

The following chapter sets out four broad areas where reforms could happen within the current framework to better facilitate the future of offshore wind.

Allocation of risk, structuring of divestment process

As the offshore transmission divestment process has progressed, areas relating to the allocation of risk between the generator and bidders (and subsequent owners) have revealed themselves and remain unresolved to date:

Generator Commissioning Clause (GCC)

The current GCC dictates that divestment of the transmission asset must occur within 18 months of issuance of the completion notice.[4] The transaction then faces time pressure to meet the deadline or risk the ceasing of generation and criminal prosecution against developers, and this very significant risk is not mirrored on the potential bidder, which only risks losing preferred bidder status for delayed divestment and an inability to recoup costs attributed to delay. This creates undue commercial leverage into the hands of the OFTO during the transaction. With increasingly large and complex transactions, this pressure to divest becomes more intense for the generator, who may become forced to accept unfavourable terms that would normally be deemed unacceptable had the transaction occurred in a more commercial setting.

Extensions to the 18-month time period are available at the discretion of the Secretary of State for BEIS but require secondary legislation and as such are difficult to obtain. Such extensions would also only represent a very resource intensive stop-gap to specific transactions as opposed to an enduring solution.

It is important to highlight that the GCC timescale also does not take into account factors outside of the developer's control. In particular, the timing of when Ofgem elects to start the invitation to tender (ITT) process represents a large potential barrier to completing a transaction on time. ITT represents a major milestone in the divestment process to attract buyers. However, under current practice, the start of ITT is not timed with the completion notice, and the recent TR6 consultation included proposals to start ITT at an even later stage, which would have significantly increased the risk of GCC breach beyond the already untenable position today.

A simple solution may be to extend the GCC to 24 months. However, this will in itself not solve the balance of risk between generator and OFTO bidders. To more fairly allocate risk there should be equal risk to both developer and OFTO by missing the deadline. This would reduce the power imbalance which can impact negotiations. A solution such as also timing the start of the GCC with the beginning of the Invitation to Tender (ITT) phase may redress the solution in a more complete and enduring manner. Should extensions still be required, it may also be necessary to ensure that Ofgem legally is given sufficient flexibility to grant an extension should that be necessary.

Income Adjusting Events (IAE)

Handling of IAEs can be viewed as a further ambiguity on the allocation of risks between all parties. Despite a response from Ofgem on IAE policy in November 2018 which advances the topic of preparing for such events, there is no clarity on who would ultimately bear such costs.

The route by which OFTOs mitigate risk could effectively place the original asset developer as the "insurer of last resort". This presents an unsustainable position towards developers who have provided the necessary diligence in order to transfer the assets over to the OFTO.

Industry can make a strong case for socialisation of IAE costs through wider TNUoS instead of local TNUoS charges. This should retain the low cost of capital whilst minimising risks for the generator who has no legal rights towards the transmission asset once it has been transferred to the OFTO. We consider that this is consistent with Ofgem's position on IAEs, which was partly based on the approach for PFI projects (where the taxpayer is the insurer of last resort).

4. The completion notice is currently timed with issuance of the ION-B notice

Structural duplication of efforts within the overall regime

The industry sees an increasing trend of larger offshore wind farms being constructed and delivered over time, primarily as a way to improve project economics.

Delivery of larger wind farms, which can be installed at increasingly further distances from shore to obtain sites with greater wind speeds, have meant that developers will be choosing innovative technology such as larger turbines and alternative transmission designs. Taking these projects into the divestment process has become more difficult due to the increased size and complexity of the transaction, resulting in significant time and resource constraint on all parties, including Ofgem, to complete the transaction.[5]

It is clear that overall value to consumer for UK projects is retained via competitive auctions for Contracts for Difference (CfD), which has seen agreed prices for delivery lowered by 67% between the first and third rounds.[6] The CfD mechanism already utilises a thorough set of milestones and processes to ensure value to consumers and drive cost reduction.

For example, under the CfD, developers must prove that a contract is mature, both through the eligibility process for the auctions and through the requirements of the CfD. All CfD projects are required to have a Crown Estate (TCE) / Crown Estate Scotland (CES) lease for access to the seabed, planning permission, and a grid connection. After the CfD is signed, projects are required to prove to the counterparty, the Low Carbon Contracts Company (LCCC), that the project is mature through the requirements for the Milestone Delivery Date (MDD). Ofgem could streamline its qualification process by relying on projects meeting the milestones set out in the CfD, the main applicable one being the MDD. A streamlining of processes would therefore reduce Ofgem's work at the qualification stage.

5. These issues are further described in the next chapter on innovation and optimisation
6. AR1 included offshore wind strike prices of £119.89/MWh compared with £39.65/MWh in AR3

Additional guidance to allow for innovation and optimisation

The industry's increasing experience in developing, owning and operating offshore wind farms coupled with the pace of technological change means that there is growing sophistication in the ways projects can be optimised, and how innovation can expand the role of offshore wind farms.

For example, optimisation would refer to ways to increase performance and efficiency to an offshore wind farm. This can include measures such as providing combined reactive compensation schemes that allow a combination of both the wind turbines and transmission design to meet grid compliance (as opposed to two separate designs that duplicate efforts). At distance, it may also include switching the transmission medium to HVDC. Optimisation could also include optimisations for the operational phase of the asset through measures to improve overall transmission asset integrity, despite the developer no longer owning the assets.

More innovative measures could increase the role of offshore wind in the energy system. This may include pairing an offshore wind farm with complementary technology to enhance provision of system services, which would require additional equipment to be installed at the substation.

Risk of disallowance

Chief amongst the risks associated with innovation and optimisation activities is the risk of disallowance for these measures, would occur relatively late into the divestment process. Disallowance means that investment already made by the developer cannot be recouped. This represents a significant disincentive to develop and implement innovative and optimised solutions that would be better than accepted practice that the current framework recognises. The risk of disallowance appears in the late stage of the transaction (i.e. after any spending has already occurred) and would be on discretion grounds based on decisions by Ofgem, which further adds risk in knowing if innovative or optimisation actions have grounds for disallowance.

> A solution to mitigate this risk may be to establish an "approval in principle" process, whereby generators can approach Ofgem prior to design and investment decisions being made to obtain guidance on how a solution will be viewed in the cost assessment process. By having an early stage understanding of the innovation and an approval to proceed, This would foster innovative solutions and reduce the risk of disallowance, which more broadly reduces investment certainty and creates confidence.

The risk of disallowance also extends into the optimisation measures that developers may wish to take to maximise availability. One route to do this would be to procure spare parts with long lead times that could be obtained during the construction phase and therefore procured more efficiently as part of a larger work package. These parts would allow an expedited return-to-service during any outages as they would be immediately available. However, the sale and transfer of these parts are not guaranteed during the divestment process and presents a risk to the generator, despite how parts could increase availability.

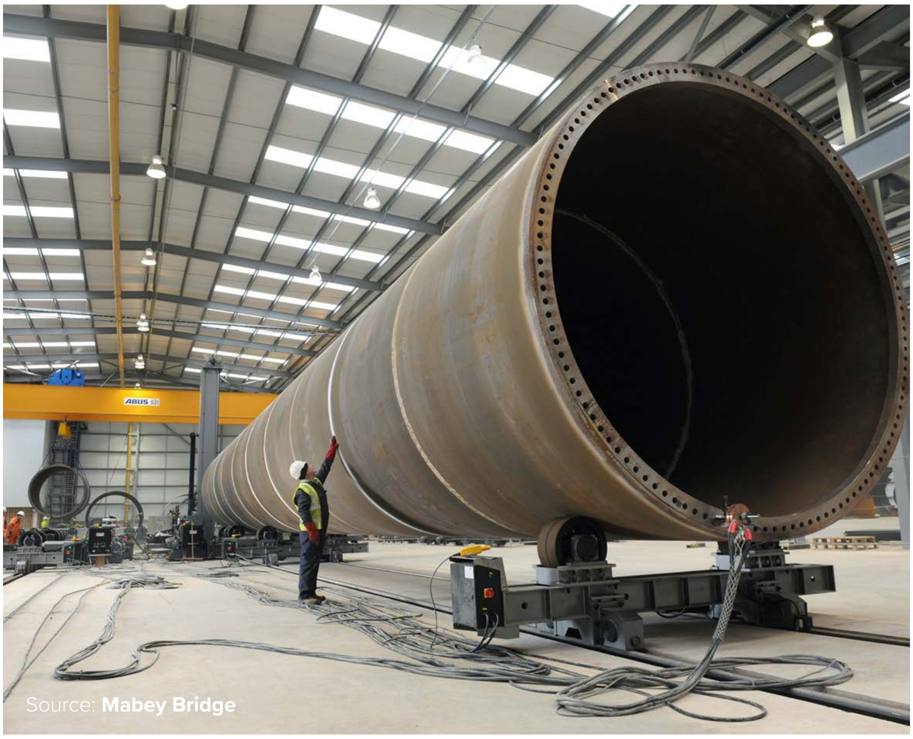
> It would therefore be preferable to require the OFTO to maintain an agreed set of strategic spares with the generator (such as cable joints, relays etc) for the duration of the licence. The availability of spare parts, and the transfer of those parts could also lead to more efficient transmission design, which would minimise the need to build full redundancy into the connection design if parts are known to be available for quick resolution of issues.

Creating guidance on co-location for offshore as exists in onshore

As an emerging trend, co-located generation sites are beginning to be developed. Pairing variable generation with a complementary technology offers a lot of potential to increase the role of renewable energy in increasing the availability of ancillary services and improve system flexibility. As part of the increasing deployment of co-located generation, guidance relating to how such power plants can be added to the system are emerging. This comes in the form of connection guidance , as well as code modifications to clarify use of system charges . For offshore projects, a layer or ambiguity exists with regards to how co-located units could connect into what would be offshore transmission assets.

“As an emerging trend, co-located generation sites are beginning to be developed”

For co-located units that may connect into the offshore transmission system, in addition to providing a level-playing field with onshore, it would provide additional clarity to developers if guidance and clarifications are offered in how such assets could be connected to the offshore transmission system and offer services to the total system. This should also include clarifications on ownership boundaries of assets (to avoid disallowance) as well as clarifying the relevant licence conditions and areas of the grid code that would facilitate deployment of services via offshore transmission


Source: **Mabey Bridge**

7. National Grid ESO – Introduction to Co-location
8. CMP316 – TNUoS Arrangements for Co-located Generation Sites

"Generators can currently minimise risk in the construction phase through the 'Generator-build option'"

Source: **Ørsted**

Reducing risk and improving O&M and asset health for transmission assets

Offshore wind farms see the generator as the sole user of the offshore transmission network that is sold to the OFTO. This makes the generator sensitive to actions taken by the OFTO.

However, generators are unable to accurately determine the asset health of transmission assets as data is not shared with them upon divestment. A misalignment of OFTO O&M incentives can therefore present a risk to generators if OFTOs use maintenance strategies that may affect generation. For example, it is unclear how the OFTO availability incentive accounts for interlinks and therefore maintenance strategies. Generators have also seen examples of short-term works (and indeed non works) to infrastructure that are not conducive to maintaining assets into the long-term.

Generators can currently minimise risk in the construction phase through the "Generator-build option". Similarly, Generators have the opportunity to minimise risk in the O&M phase by offering O&M services to the OFTO. It is imperative that this option is maintained and strengthened ("Generator O&M").

A range of options may exist on how to improve overall asset health:

The option to have operations and maintenance delivered by the generator should be confirmed. As a sole user of both generation and transmission assets, this would provide an alignment that would maximise the lifetime of both assets. It should be assessed whether this could be included as one of the prerequisites of the OFTO tender if the generator choses to do so.

For solutions where the OFTO delivers the O&M service the following issues would be important:

Tied to options on extending the lifetime of assets beyond the tendered revenue stream (described in the next section), there can be a lot of value derived through sharing data to determine how overall asset utilisation can be increased. For example, assessment of bids based on ability to drive availability higher, willingness to share information on asset health with generator, allow greater generator input to O&M.

Furthermore, a greater say for generators in how the transmission asset is going to be managed is going to be important as efficiencies will arise from holistic solutions that can cover both wind farm and transmission.

Introduction of an independent technical audit (once every 2/3 years) if the OFTO performs O&M services to give confidence O&M provision is up to industry best practice and assets aren't being sweated without adequate investment.

Clarity on transmission assets beyond the 20/25 year TRS

Coupled with issues surrounding O&M, a longstanding issue with the existing framework is that whilst the Tendered Revenue Stream (TRS) exists for 20 years (and more recently 25 years for the coming tender rounds), the overall asset lifetime of both generation and transmission assets can be longer than these periods.

There is an enormous potential to explore life extension that would maximise the utilisation of assets and provide more green energy to consumers. Life extension optimisations could keep both generation and transmission assets on the system for longer, representing a benefit to consumers who get more value from installed equipment, as well as continued contribution to decarbonisation targets.

Source: **Proven Energy**

The present framework makes unlocking this additional value unviable. In addition to the difference between the TRS and the asset lifetimes, the additional misalignment created by having a different owner for generation and transmission assets makes it impossible to introduce measures that could substantially improve the lifetime of these assets as described in the optimisation section above. The separate ownership structure means that generators have no information on the maintenance and quality of OFTO assets whilst under their ownership, making it hard to make decisions regarding suitability and economic viability of life extension for the wind farm.

Furthermore, generators also have no clarity on the arrangements/ ownership post Year 20/25, which again will make further investments and decisions regarding life extension for the wind farm difficult. Particularly, there would appear to be no incentive for the OFTO to continue ownership after the 20/25yr TRS, and maintenance is therefore currently incentivised to be carried out along the lifetime of the TRS instead of the asset lifetime. From a regulatory asset value perspective, at the end of the TRS period, the assets will become fully paid for assets and therefore have a RAV of 0, but the burden to decommission assets remains on the OFTO. For OFTOs which may have made an assumption on the Residual Value to go beyond the initial TRS period, there is also no certainty that this will actually be the case.

It therefore becomes possible that OFTOs would notify to end their licence in Year 18.5 in order to relinquish control at the end of TRS, and maintenance may suffer further from around this point. If the licence were to be re-tendered, the costs of re-tendering may be disproportionate to the remaining benefits (as the asset is effectively fully amortised upon end of TRS from a RAV perspective).

However, if properly maintained, the transmission asset could support end-of-life options such as lifetime extension, repowering and other technical enhancements.

The issues around ensuring sufficient maintenance is less of a concern when the generator offers O&M to the OFTO as the generator would have all incentives to ensure a long lifetime of the transmission assets. However, clarity on the arrangements/ ownership post Year 20/25 will be of importance also under this option.

> “If properly maintained, the transmission asset could support end-of-life options such as lifetime extension, repowering and other technical enhancements”

In order to realise the remaining value from assets, there are a range of step-wise actions that may help address some of the deficiencies in the existing framework, as well as an enduring option around ownership that may provide maximum value:

For example, where it is clear that life extension options are viable, maintenance should be provided in accordance with the projected 35-40 year lifetime of the transmission asset as opposed to 20/25yr TRS (which is how the OFTOs are currently incentivised to carry out O&M).

Additionally, the viability of life extension would be provided for with data sharing between OFTO and generator on asset health, which should form part of the offshore transmission licence conditions. The availability of data is an important factor in making an accurate assessment of life extension options.

If a default position of extending the TRS is taken, there are significant issues that would need consideration, such as the structuring of any extension (e.g. would this be a rolling basis, or in X-year increments). With many operational assets about to enter a decision window on whether life extension is possible, there has been no traction to address these issues. Even if this course of action is pursued, it would still remain unclear if OFTOs would actually pursue extension as an option.

A more enduring solution may exist in generators seeing ownership of transmission assets returned at the end of the TRS period. This would apply to current projects with a radial connection to shore. As sole-users of these assets, the return of ownership would not be undue competition concerns on other system users. However, having the ability to own, the assets would allow the full alignment between assets that could not only see full optimisation of operations and maintenance, but unlock synergies between both sets of assets to be further developed as one singular project.

Offshore Wind Industry Council